Chapter 6: Cost Calculations

This chapter begins with an overview, including goals, challenges, and the overall philosophy underlying the costing approach used in this project for the following costs associated with EMF mitigation strategies: Total project costs (TPC), conductor loss costs, and operation and maintenance (O&M) costs. A background section is included, which describes how our costing approach was developed, and also the relationship between our approach and the one developed by Enertech for the School Measurement Project (Enertech Consultants, 1998a). The chapter concludes with sections giving specific information about how TPC, O&M costs and conductor loss costs are evaluated.

The cost estimation methodology described in this chapter and in Appendix C was reviewed by Commonwealth Associates, Inc. (CAI, 2000). CAI concluded that "… the unit prices reviewed were reasonable for the most part, but tended to be on the high side for overhead construction and on the low side for underground (10-20%)."

Users of the cost models who are concerned with the possible estimation biases can make adjustments to correct for them or use their own cost models as inputs. In either case changes within a +/-20% range are very unlikely to affect the conclusions of this report. Furthermore, in most analyses, we used a high and low cost estimate that varied by a factor of 2-3 and covered most estimates that were available from utilities or from the literature.

6.1 Overview

One overall goal of this project was to develop a computer program to evaluate various EMF mitigation strategies for new and existing power lines in the State of California. The goal of the work described in this section has been to develop expressions for inclusion in ANALTYICA® to evaluate the costs associated with building and operating power lines. Defining "base case" as the existing power line or the line which would be built if EMFs were not a consideration, these expressions are to cover both base cases and mitigation strategies.

The costs evaluated are TPC, O&M and conductor losses. The TPC costs are the costs to actually build a line (either base or mitigated case) or to retrofit an existing line for lower EMFs. O&M costs include such costs as tree trimming, repainting towers, replacing rotted wooden poles, and so forth. O&M costs can differ quite a bit from one strategy to the next, as for example when one alternative allows "live" maintenance while another requires the line to be taken out of service in order to be maintained. The conductor losses are the costs associated with the heating up of the conductors (I^2R losses), the heating up of the insulation surrounding the conductors (underground designs), or the heating up of the pipe for pipe-type underground designs. Losses can vary quite a bit as a function of which mitigation strategy is being evaluated.

There are a number of challenges to the development of these costs, especially the TPC. First of all, the number of different line types considered in (Enertech Consultants, 1998a), both distribution and transmission, is quite large: approximately 32 distinct types of transmission and 16 types of distribution. Even this list of line types is not exhaustive. In addition, the implementation of a specific line type can vary dramatically even within a single utility due to widely varying local conditions such as soil conditions and existing land use. Due to the many factors involved when a new line is to be constructed, the engineering of an optimal design, where costs are a critical consideration, can be a significant percentage of the TPC – even 10-20%.

As a result of the dramatic range of line types and possible mitigation strategies possible in Californnia, the underlying philosophy for this part of the project has been to develop models that are detailed enough to provide reasonable estimates and which remain flexible and user-friendly. There is always a trade-off between complexity of a model and ease of using and understanding it. If the models were so detailed as to cover all the possibilities in California then they would be overwhelmingly complex and there would be a very large number of them. The approach used in this project is to clearly document each cost equation available to the user. If a particular user is not satisfied with a particular model, he or she can utilize a custom approach with his or her own cost figures.

6.2 Background

The costing approach used in this work is the one developed by Enertech Consultants (1998a) for use in evaluating costs of various mitigation strategies for K-12 students in CA public schools. The EMF sources evaluated in Enertech Consultants (1998a) included transmission and distribution adjacent to or on school property, as well as localized sources such as building wiring and florescent lighting. There are two limitations of the cost models developed in Enertech (1998a) from the perspective of the present study. First, only existing EMF sources are considered so that only retrofit strategies are covered. Second, only “localized” portions of power lines are considered – only a few spans of a transmission or distribution line adjacent to school property, for example. Longer lengths of line than would run adjacent to a school, which we chose to call “generalized”, are not covered. Table 6.1 is given to clarify these limitations.

Table 6.1: Coverage of EMF Mitigation Strategies in Enertech Consultants (1998a)

EMF Mitigation Strategy	Covered by Enertech Consultants?
Retrofit of Localized Source	YES
Retrofit of Generalized Source	NO
New Construction, Localized Strategy	NO
New Construction, Generalized Strategy	NO

In order to extend the models developed in Enertech Consultants (1998a) so as to be applicable to the three cases not covered above, Jack Adams under subcontract for Decision Insights met with Lucianno Zaffanella of Enertech Consultants in January of 1998. At that time they parsed the transmission options covered in Enertech Consultants (1998a) and developed some cost equations to cover the other situations described above. During the coming weeks, similar equations were developed for distribution, and some test scenarios were considered. Dr. Zaffanella then created a work statement for Power Engineers that requested an evaluation of the cost equations for transmission and distribution, and for specific costs for the various factors included in the equations, such as dismantling costs of existing lines.

The work to extend the costing developed in Enertech Consultants (1998a) to the other cases was funded by California Department of Health Services via a contract with Enertech Consultants, where Power Engineers served as a subcontractor. The result of this contract is the document *Magnetic Field Mitigation Cost Estimates*, June 1998, by Enertech Consultants (1998b). Included in this document is the original work request written up by Enertech Consultants as well as the report written up by Power Engineers describing the results of this work.

6.3 Total Project Costs

The Total Project Costs (TPC) associated with particular mitigation strategies are covered in detail in the two documents (Enertech Consultants, 1998a, 1998b). In this section we give an example calculation: convert a "flat" configured 3-wire distribution line to a compact delta configuration. The first document (Enertech Consultants, 1998a), which is the main one, examines in detail the use of local retrofit strategies for existing sources, which in the case of power lines means a mitigation strategy used for existing lines for a few spans. The other cases which have to be covered within the scope of the "Power Grid" project are retrofit – generalized cases (more than a few spans, so that the cost equations developed in Enertech Consultants (1998a) no longer apply) and the new construction for the local and generalized cases. In this section we will show how the formulas for the various implementations of the "convert to compact delta" configuration are arrived at.

Retrofit an existing field source – local.

"Change flat into compact delta" is the field reduction option 2.2 in Enertech Consultants (1998a). The cost equation given is:

$C = k_1 + k_2\,(N_s+1)$ (Enertech Consultants, 1998a; CE 2.2)

$\mathbf{k_1}$ is a fixed cost for engineering, permits, and mobilization. $8,100 (6,400 to 9,700),

$\mathbf{k_2}$ is the cost in $/structure for modification of existing poles. $1,750 (1,370 to 2,140),

N_s is the number of spans to which the strategy would be applied. The reason for 1 being added to **N_s** is that the structure at each end of the span must be modified. For example, if one span is modified then two structures must be modified.

If we are retrofitting three spans of existing lines, then, using the average values given in Enertech (1998a):

$$C = \$8,100 + \$1,750(3+1) = \$15,100.$$

We mention here that SAC members raised questions concerning the ability of the existing poles to withstand loading stresses due to the asymmetric placement of the conductors. If this is the case, then instead of modifying the existing structures the poles would have to be replaced, and the cost of a new pole would have to be used in (Enertech Consultants, 1998a; CE 2.2). If the poles are to be replaced then dismantling costs of the existing lines also have to be considered.

Retrofit an existing field source – generalized case.

How do we extend the above to the case where, for example, we want to convert a mile to compact delta? A main difference is that now it no longer makes sense to express the engineering, permitting and mobilization costs as fixed, as they likely will increase in proportion to the magnitude of the project. This strategy is not explicitly covered in either Enertech document, so we modify the local case similarly to how other local versions of the cost equations are converted to the general case. See for example Enertech Consultants (1998a) cost equation (8) on p. 8 of Appendix I, where instead of expressing the engineering costs as fixed, they are now expressed as a fraction of the total cost. As for the local case, if the existing poles cannot handle this new configuration, then the cost of new poles and the cost of dismantling the existing poles would have to be added to the total costs. The new cost equation, which assumes that the existing poles are adequate, is then:

$C = (1+k_1)\ [k_2*(N_s+1)]$, (Enertech, Consultants 1998a; CE2.2 revised for general case)

where

k_1, the engineering, permitting, and mobilization, is now expressed as the percentage of total. 15% (10-20) (Enertech Consultants, 1998b; p.31),

k_2 is the same as for the local case.

For one mile (27 spans) $C = (1 + 0.25)\ (1,750*(27+1)) = \$61.3$ k

Construction of a new distribution line using the compact delta configuration – generalized case.

The new construction cost equation is given as equation (8) in Enertech Consultants 1998a), Appendix I:

$C = (1+k_1)\ \{k_2*3*L_2 + k_{10}*L_2/200 + k_{14}*L_2\}$, where

L_2 is the total length of the 3-phase feeder (feet). A 200' distance between spans is assumed, so that $L_2/200$ is the number of spans,

k_1, the engineering, permitting, and mobilization, is now expressed as the percentage of total, 15% (10-20) (Enertech Consultants, 1998b, p.31),

k_2 is the cost of the 12kV, 600 A conductors (installed on poles) per unit of length ($/foot) $5.14 (4.53 to 5.76) (Enertech, 1998b, p.32),

k_{10} is the average cost of poles for the three phase primary in $/pole, including insulators and hardware. $1,900 (1,700 to 2,100) (Enertech, 1998b, p.33),

k_{14} is the average cost of right of way acquisition and clearing ($foot) for a 20' ROW $250 (30 to 470) (Enertech, 1998b, p.33).

The values given here for the average pole costs require explanation. The Enertech cost equation gives a single pole cost. Power Engineer gives as typical 80% tangent, 10% angle, and 10% dead end. The figures provided are weighted according to the proportion of the three pole types.

Using the values given in Enertech Consultants (1998b, p.33) for 12 kV lines, and assuming a 1 mile stretch of line is being installed, there are 27 spans:

$$C = (1 + 0.15) * (5.14*3*5280 + 1{,}900*27 + 250*5280) = \$1{,}928\text{ k}.$$

The dominant cost here is the ROW purchase and clearing cost, which is assumed to be quite high for a typical suburban area.

The construction described here, new construction of 3-wire delta, is PG&E's preferred construction for new lines under the "No and Low Cost" guidelines adopted by that utility (PG&E, 1994). This design is a low field design by comparison with overhead designs. Thus if a new distribution line scenario were to be modeled in that utility, and for example, an underground and an overhead line were to be compared, then it appears that the 3-wire Delta would be the base case design considered.

Construction of a new compact delta configured distribution line – local

The use of a mitigation strategy in new construction on a local basis implies that there is some base case which this "local" case is used to replace for a sensitive stretch. This could be considered where the proposed line runs adjacent to a school, day care, or hospital for example. Compact delta is already a "base case" that would be used on a general case basis, so that "local" use of this strategy, meaning for a few spans, does not make sense. If, for example, we are considering local pole height increases, then the cost equation would be the same as for the general case, except that the difference in the pole costs would have to be accounted for.

6.4 Calculation of conductor losses

The question of how losses are calculated and, in particular, how overhead and underground transmission designs compare with respect to losses is addressed in the following paragraphs. A few points need to be made at the outset:

- The decision of what conductor size will be utilized in a design is a research topic in and of itself. One of a number of tradeoffs to consider is that while thicker conductors cost more, they have lower resistance and thus lower losses. Thicker conductors also have a higher rated ampacity.

- The set of conductors available within a utility is limited - for example at 115 kV OH conductor ampacities might range from 300 to 1,000, with 5 conductor choices in that range.

- Overhead designs are subject to resistive, or I^2R, losses only. Solid dielectric designs, of which XLPE is one type, additionally have dielectric losses due to the heating of the dielectric. Dielectric losses depend on the voltage but not on the current. For pipe-type designs, there are pipe-heating losses as well, which depend on the current.

- One of the main difficulties with solid dielectric designs is the difficulty with dissipating heat. For this reason, a double circuit design will require larger conductors than a single circuit design at the same voltage and rated ampacity, due to mutual heating of the two circuits. Also, as the rated ampacity rises, the required conductor size increases quite rapidly. Guidelines are available for underground designs.

As part of our "retrofit existing transmission" module, we have conducted calculations for three line voltages, ranging from 69 kV to 230 kV. The overhead conductors chosen are in use by PG&E and could be suitable for 600 A. ampacity. Other conductors might be chosen depending on the local conditions. The typical currents are taken from PG&E's "Blue Book", and of course could vary quite a bit depending on demand. The assumed loss factor is 0.5, which is in the range given in Enertech Consultants (1998a). In the calculations below, note that I^2R and pipe heating losses are multiplied by the assumed loss factor, whereas dielectric losses are voltage and geometry dependent and do not depend on the loading.

Loss Calculations -- comparison of XLPE, OH, and Pipe Type

This subsection describes how we calculated losses from overhead line and underground cables. The calculations make the following assumtions:

Rated ampacity: 1000 A, typical current: 500 A.

Overhead 230 kV Double circuit: 1113 KCM Aluminum, with resistance of 0.0874 Ω/(Cond-Mile) = 1.655 E-5 Ω/(Cond-foot)

In Enertech (1998b), the following conductor sizes are assumed:

For Double Circuit 230 kV, Ampacity of 1,000 A.: 2,750 kcmil XLPE Aluminum

also, for Double Circuit 230 kV, Ampacity of 1,000 A: 2,500 kcmil HPFF Aluminum

<u>Overhead</u>

At rated ampacity, can calculate the I^2R losses as: $6*1000^2*1.655$ E-5 = 99.3 Watts/foot. Multiply by loss factor of 0.5 to get: **<u>49.65 Watts/foot</u>**

<u>XLPE</u>

At rated ampacity, I^2R losses are given by ETC as: 47.02 W/foot (Enertech, 1998b, p. 3) and dielectric losses are: 2.377 W/ft.

So, total losses are 0.5*47.02 + 2.377 = **<u>25.89 W/ft</u>**

<u>Pipe Type</u>

At rated ampacity, I^2R losses are given by ETC as: 8.75 W/(cable foot) (p. 19 new data) so, for Double circuit: 6*8.75 = 52.5 W/foot. Pipe losses: 2.51 W/foot. Dielectric losses: 3.65 W/foot. Total losses are then: 0.5*2.51 + 0.5*52.5 + 3.65 = **<u>31.15 W/ft</u>**

While the above calculations used a loss factor of 0.50, the most recent revised AANLYTICA models use more realistic loss factor of 0.33.

6. 5 O&M Costs

Data sources

For this report, we draw on several sources of data: data presented by California investor owned utilities (CPUC, 1998), a British study looking at European UG and OH (International Copper Association, 1995), summary data presented in a Rhode Island study (CAI 1992), national data (FERC 1992), and data provided by Enertech Consultants (Enertech 1998b).

California data

It is worth noting that in the summary of the utility responses to PUC questions which was distributed to the SAC early in 1998 some of the transmission and distribution data was lumped together. If one looks at the actual responses of the individual utilities, only two utilities reported data for OH transmission: 0.125 $/ft (Pacificorp) and 0.29 $/ft (SDG&E). Only SDG&E gave a figure for UG transmission: 0.19 $/ft. This results in $1.1 k/mile/year for OH, and 1.0 k/mi./yr. for UG.

British study (International Copper Association, 1995)

The data that most closely pertains to the present study is presented in Annex 3, p. 1 of the report by the International Copper Association (1995). The data is given below, and averages are taken. Figures are given in US $ (thousands/km/yr).

Table 6.2: Overhead vs. Underground Cost

(International Copper Association, 1995, estimates are in thousands of US Dollars per kilometer per year)

Country, voltage	OH	UG
France, 225 kV	3.0	1.0
Norway, 132 kV	1.8	1.0
Germany, 110 kV	2.8	0.5
Germany, 110 kV	2.4	0.3
Switzerland, 100 kV	2.4	0.4
Averages	2.48	0.64

This works out to $3.97 k/mi./yr. for OH, and $1.02 k/mi./yr. for UG. It should be noted that all UG is XLPE in this data set. It also should be noted that this study was funded by the International Copper Association, so that there may be a bias towards emphasizing the merits of undergrounding and thus purchasing more copper. We did find that the numbers given in this study were on the low end for underground O&M and on the upper end for overhead O&M.

National statistics

In a study funded by the state of Rhode Island, CAI presents a useful summary of the Federal Energy Regulatory Commission data (FERC, 1992) in Exhibit 23, sheet 2. There, they present figures for lines in service, which are taken from FERC (1992, page 44) - for overhead lines the data is presented in structure miles, while for underground lines the data is circuit miles. For the utilities considered, there were 352,127 structure miles of overhead lines and 5,166 circuit miles of underground lines. The summary results are:

$885/structure mile for overhead lines,

$5,714/circuit mile for underground lines.

Note that if we were to put overhead and underground on an equal footing, both figures should be for single circuit or for double circuit. If the underground data were reported as double circuit, the figure probably would be significantly higher. We assume that the underground lines reported in this dataset are almost exclusively pipe-type.

Certainly in the Consolidated Edison and Boston Edison areas the underground system is almost exclusively pipe-type.

Enertech data

In the most recent dataset provided by Power Engineers under subcontract with Enertech Consultants, O&M figures are provided for both solid dielectric and pipe-type designs (Enertech, 1998b). In this work, 230 kV double circuit HVED and Pipe Type systems were compared. Their figures for levelized annual maintenance cost ($/year/mile) are:

	Average	Maximum	Minimum
Solid dielectric	1,200	1,320	1,080
Pipe Type	9,600	10,560	8,640

This data seems to mesh with other data presented above. The British data (International Copper Association, 1995) presented is for solid dielectric, and is at the low end of the Enertech data. The US national data for single circuit ($5,714) is about 60% of the figure of $9,600 presented here, which seems reasonable when comparing single to double circuit. It also is reasonable to assume that O&M costs for California pipe-type systems are similar to those around the country.

Conclusions and limitations of the data

The data provided by the various sources covered in this section are summarized in Table 6.2. It does appear that the O&M costs for overhead and XLPE lines are in the same general range -- in the neighborhood of $1k/mile/year. It also appears that O&M for pipe type is in the general range of 5-7 times higher, due primarily to the costs associated with the fluid pressurization system.

Several complexities with this issue need to be brought out. Since there is very limited XLPE in use in the US, and little or none in California at higher voltages, directly applicable US O&M data is not available. Also, different utilities may have different methods of recording and reporting O&M and have different O&M philosophies.

In spite of these limitations, the data given above are useful for the purposes of the present study. The philosophy of the cost data is to provide roughly accurate figures for first estimates. For a specific utility considering a specific line design under specific local conditions, of course much more accurate data can be provided. The present results are that, at least for transmission, it appears that O&M is not an important cost factor in comparing underground and overhead designs. In comparing two overhead designs which are fairly close in their total project costs, such as a compact design which precludes live line maintenance and a standard design which does allow live line maintenance, relative O&M costs could well be an important factor.

Table 6.2: Summary of O&M Data

Type of line	Minimum O&M (k$/mi/yr)	Maximum O&M (k$/mi/yr)
Overhead	**0.885**	**2.48**
Solid Dielectric	**1.02**	**1.32**
Pipe Type	**5.71**	**10.5**